

DIRECT TESTIMONY AND EXHIBIT
OF
BRIAN HORII
ON BEHALF OF
THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF
DOCKET NO. 2018-2-E
IN RE: ANNUAL REVIEW OF BASE RATES FOR FUEL COSTS FOR
SOUTH CAROLINA ELECTRIC & GAS COMPANY

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Brian Horii. My business address is 101 Montgomery Street, San Francisco, California 94104. I am a Senior Partner with Energy and Environmental Economics, Inc. ("E3") and have been retained by the South Carolina Office of Regulatory Staff ("ORS") to assist in the analysis of South Carolina Electric & Gas Company's ("SCE&G" or "Company") avoided capacity cost and avoided energy cost calculations, and review the Value of NEM methodology, in this Docket.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have thirty (30) years of experience in the energy industry. My areas of expertise include avoided costs, utility ratemaking, cost-effectiveness evaluations, transmission and distribution planning, and distributed energy resources. Prior to joining E3 as a partner in 1993, I was a researcher in Pacific Gas and Electric Company's ("PG&E") Research & Development department, and was a supervisor of electric rate design and revenue allocation. I have testified before commissions in California, British Columbia, and

Vermont, and have prepared testimonies and avoided cost studies for utilities in New York, New Jersey, Texas, Missouri, Wisconsin, Indiana, Alaska, Canada and China.

I received both a Bachelor of Science and Master of Science degree in Civil Engineering and Resource Planning from Stanford University. My full curricula vita is provided as Exhibit BKH-1.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA (“COMMISSION”)?

A. Yes, I testified before this Commission on behalf of ORS in reviewing SCE&G’s avoided cost calculations.

Q. WHY WERE YOU RETAINED BY ORS IN THIS PROCEEDING?

A. ORS retained E3 to once again assist in reviewing SCE&G’s avoided cost calculations to:

1) Verify the Company is using the avoided cost methodology approved by the Commission;

2) Confirm the methodology meets the Public Utility Regulatory Policies Act of 1978 (“PURPA”) requirements; and

3) Verify the avoided cost rates requested by SCE&G in this Docket are a reasonable result of the approved avoided cost methodology.

ORS also retained E3 to conduct an analysis of the SCE&G’s Value of Distributed Energy Resource (“DER”) calculation to:

1) Verify the Company has populated each of the eleven (11) categories according to the methodology established in Order No. 2015-194;

2) Confirm, for each category with a value of zero, that the Company does not have sufficient capability to accurately quantify those costs or benefits to the utility system; and

3) Verify, for each category with a value other than zero, that the value assigned is a reasonable result of the Company's ability to accurately quantify the costs or benefits to the utility system.

My prior work experience in this subject matter includes the following:

- Developed the methodology for calculating avoided costs used by the California Public Utilities Commission for evaluation of Distributed Energy Resources since 2004;
- Developed the methodology for calculating avoided costs used by the California Energy Commission for evaluation of building energy programs;
- Authored avoided cost studies for BC Hydro, Wisconsin Electric Power Company, and PSI Energy;
- Provided review of, and corrections to, PG&E avoided cost models used in their general electric rate case;
- Developed the integrated planning model used by Con Edison and Orange and Rockland Utilities to determine least cost DER supply plans for their network systems;
- Developed the hourly generation dispatch model used by El Paso Electric Company to evaluate the marginal cost impacts of their off-system sales and purchases;

- 1 • Produced publicly vetted tools used in California for the evaluation of energy
- 2 efficiency programs, distributed generation, demand response, and storage
- 3 programs;
- 4 • Analyzed the cost impacts of electricity generation market restructuring in
- 5 Alaska, Canada, and China; and
- 6 • Developed the “Public Tool” used by California stakeholders to evaluate Net
- 7 Energy Metering program revisions in California.

8 **Q. PLEASE BRIEFLY DESCRIBE THE REQUIREMENTS OF PURPA AND HOW**
9 **THEY RELATE TO THE PR-1 AND PR-2 RATE SCHEDULES PROPOSED BY**
10 **THE COMPANY.**

11 **A.** In 1978, as part of the National Energy Act, Congress passed PURPA which was
12 designed, among other things, to encourage conservation of electric energy, increase
13 efficiency in use of facilities and resources by utilities, and produce more equitable retail
14 rates for electric consumers.

15 To help accomplish PURPA goals, a special class of generating facilities called
16 Qualifying Facilities (“QFs”) was established. QFs receive special rate and regulatory
17 treatments, including the ability to sell capacity and energy to electric utilities. All electric
18 utilities, regardless of ownership structure, must purchase energy and/or capacity from,
19 interconnect to, and sell back-up power to a QF. This obligation is waived if the QF has
20 non-discriminatory access to competitive wholesale energy and long-term capacity
21 markets.

22 In SCE&G’s service territory, Small Power Producers and Cogenerators that are
23 designated as QFs and have capacity less than or equal to 100 kilowatts (“kW”) are

1 compensated under SCE&G's Rate PR-1. Power purchased from QFs with capacity greater
2 than 100 kW and less than or equal to 80 megawatts ("MW") is compensated under
3 SCE&G's Rate PR-2

4 **Q. PLEASE DESCRIBE THE METHODOLOGY SCE&G USED IN THIS FILING TO**
5 **CALCULATE ITS AVOIDED ENERGY AND AVOIDED CAPACITY COSTS.**

6 **A.** SCE&G calculates avoided energy costs using the avoided cost methodology
7 known as the Differential Revenue Requirement ("DRR"). This method calculates the
8 revenue requirements associated with two (2) resource plan scenarios: a base case without
9 the QF, and a change case with the QF. This methodological framework is one of the
10 accepted methods for calculating PURPA avoided costs.

11 For the long-run avoided energy cost calculations, in both the base case and the
12 change case, SCE&G uses PROSYM, a production cost model, to simulate the
13 commitment of generating units to serve load on an hourly basis over a 15-year Integrated
14 Resource Plan ("IRP") planning horizon. The base case is constructed by using load
15 forecasts and supply side resources as described in the IRP. The change case modifies the
16 base case load forecast by subtracting zero-cost energy following the profile of a 100 MW
17 solar photovoltaic ("PV") generator. Finally, the avoided energy costs are levelized and
18 adjusted for taxes and working capital.

19 SCE&G has not provided a calculation for long-run avoided capacity costs.

20 **Q. IS THE METHOD USED BY SCE&G TO CALCULATE AVOIDED ENERGY**
21 **COSTS CONSISTENT WITH THE METHODOLOGY APPROVED BY THE**
22 **COMMISSION?**

1 **A.** Yes. The DRR methodology, as approved by the Commission in Order No. 2016-
2 297, supports various input models. In Docket Nos. 2016-2-E and 2017-2-E, SCE&G
3 calculated avoided energy costs by using the DRR approach modeling a QF with a constant
4 100 MW generation profile for the change case. In this Docket, SCE&G applies the DRR
5 approach modeling a QF with a solar profile for the change case. The shift of input models
6 for the change case from a constant profile to solar PV profile is a valid application of the
7 DRR methodology for the specific case of a solar generator.

8 **Q. PLEASE EXPLAIN WHY SHIFTING TO A SOLAR PROFILE IS AN**
9 **IMPROVEMENT OVER THE PRIOR METHOD.**

10 **A.** Previously a constant generator profile was used to calculate the difference in
11 revenue requirements between the base case and the change case, with costs collected into
12 four (4) time of use ("TOU") periods comprised of peak season and off-peak season, and
13 peak hours and off-peak hours within each season. The profile essentially assumed constant
14 solar output over the TOU period. Under the updated methodology, SCE&G derives a
15 change case by using a 100 MW solar profile. Given SCE&G's assertion that the vast
16 majority of recent and future QF resources are solar, it is an improvement to use an avoided
17 energy cost which more closely tracks the avoided energy for solar generation.

18 **Q. PLEASE DESCRIBE ANY OTHER UPDATES MADE BY SCE&G TO THE**
19 **AVOIDED ENERGY COSTS.**

20 **A.** In addition to the change as described above, changes in avoided energy costs are
21 driven by differences in fuel forecasts, load forecast, and in supply side resources as
22 reported in the 2018 IRP. In the 2017 IRP, SCE&G projected supply purchases from new
23 nuclear plants in 2020 and 2021. In the 2018 IRP, the construction of these nuclear plants

1 was canceled, with the capacity shortfall made up by increased solar and baseload
2 combined-cycle gas plants. This change in supply side resources likely had a small effect
3 on avoided energy cost calculation because the avoided energy cost is dependent on cost
4 for marginal units, and both nuclear and combined-cycle gas plants are listed as baseload
5 resources in the SCE&G IRP. I have reviewed the fuel price forecasts which SCE&G used
6 in calculating the avoided energy cost for both the 2017 and 2018 fuel adjustment
7 proceedings. These fuel price forecasts are consistent and similar. Finally, there is a slight
8 change in long-term annual sales growth (from 1.2% territorial sales growth annually to
9 1.1%) (SCE&G 2018 IRP). There appears to be no major changes in network
10 configurations or import/export assumptions used by SCE&G.

11 **Q. ARE THE UPDATES IN AVOIDED ENERGY COSTS A REASONABLE AND**
12 **CONSISTENT RESULT OF THE METHODOLOGY USED BY SCE&G?**

13 **A.** Yes. SCE&G applied the approved DRR methodology to calculate avoided energy
14 costs. SCE&G presents avoided energy costs calculated using a solar profile, as well as
15 avoided energy costs calculated using a constant 100 MW profile (Lynch, p. 11). Given
16 the relative similarity in fuel forecasts and minor changes in load, it is reasonable that the
17 avoided energy costs using the constant 100 MW do not change significantly from last
18 year. Furthermore, as SCE&G is proposing to set these avoided energy rates for solar
19 resources, it is reasonable to use a solar specific profile in calculating the avoided energy
20 costs. I agree with SCE&G's assertion that a solar generation profile can cause operational
21 and ramping issues which a constant profile does not cause. Thus, it is reasonable that the
22 avoided cost for energy using a solar profile is lower than the avoided cost for energy using
23 a constant energy profile.

1 **Q. IN YOUR OPINION, IS THE METHOD USED BY SCE&G TO CALCULATE**
2 **AVOIDED ENERGY COSTS APPROPRIATE?**

3 **A.** Yes, it is appropriate for solar generators.

4 **Q. PLEASE DESCRIBE THE UPDATES MADE BY SCE&G TO THE AVOIDED**
5 **CAPACITY COSTS.**

6 **A.** SCE&G has implemented a dramatic change in approach by not providing any
7 avoided capacity cost calculations in this proceeding.

8 **Q. WHAT ARE SCE&G'S STATED REASONS FOR NOT PROVIDING ANY**
9 **CALCULATIONS OF AVOIDED CAPACITY COST?**

10 **A.** Company witness Lynch asserts that new solar projects would not provide any
11 capacity reductions, so the avoided capacity value for the PR-2 rate is de-facto zero. He
12 further states that SCE&G will not offer the PR-2 rate to non-solar resources, so there is
13 no reason to provide an avoided capacity cost estimate in this proceeding. Further, when
14 ORS requested SCE&G to provide a calculation of avoided capacity costs for potential
15 non-solar resources, SCE&G did not provide any estimate, stating that it had no
16 information responsive to the request.

17 **Q. DO YOU AGREE WITH SCE&G THAT NEW SOLAR PROJECTS WILL**
18 **PROVIDE NO CAPACITY VALUE?**

19 **A.** No.

20 **Q. WHAT IS THE BASIS FOR YOUR DISAGREEMENT WITH SCE&G ON THE**
21 **CONTRIBUTION OF SOLAR TOWARD REDUCING CAPACITY COSTS?**

22 **A.** SCE&G asserts that "SCE&G needs as much capacity in the winter as it does in the
23 summer" (Lynch, p. 15) and "[b]ecause solar does not provide capacity during the winter

1 period, the Company is unable to avoid any of its projected future capacity.” (Lynch pp15-
2 16). SCE&G, however, has not adequately demonstrated that winter capacity needs are
3 the same or greater than summer capacity needs. If SCE&G capacity needs are instead
4 driven by the summer season, as SCE&G has historically stated (e.g.: SCE&G 2017 IRP
5 pp. 37-38), then incremental solar would continue to provide capacity benefits, and
6 incremental solar should therefore continue to receive avoided capacity cost compensation
7 in the PR-1 and PR-2 rate.

8 **Q. WHAT INFORMATION HAS SCE&G PROVIDED TO SUPPORT SCE&G BEING**
9 **CONSTRAINED BY WINTER CAPACITY?**

10 **A.** SCE&G states that “Since SCE&G’s Reserve Margin Study shows that SCE&G
11 needs as much capacity in the winter as it does in the summer, a resource has to provide
12 capacity in the winter as well as the summer in order to avoid the need for capacity and
13 thereby have capacity value.” (Lynch, p. 15). The reserve margin study states that SCE&G
14 requires 50% more capacity reserves in the winter as compared to the summer (21% vs
15 14% reserve margin). Referring to the SCE&G forecast of summer and winter loads and
16 resources from their 2018 IRP in Exhibit JML-1, one sees that, in many years, the winter
17 reserve margin target of 21% would be violated before the summer reserve margin target
18 of 14%.

19 **Q GIVEN THAT INFORMATION, WHAT ARE YOUR CONCERNS WITH**
20 **SCE&G’S POSITION OF ZERO AVOIDED COST FOR INCREMENTAL**
21 **SOLAR?**

22 **A.** SCE&G has not provided a straightforward update to its avoided capacity cost
23 estimates in this Docket. Rather than simply updating inputs used to estimate the avoided

1 capacity cost, SCE&G introduced a new concept of 100% winter capacity constraints as
2 the basis for not calculating any avoided capacity cost. I have concerns that parties have
3 not had adequate opportunity to evaluate the accuracy of this winter capacity constraint.
4 In addition, the flaws and inconsistencies in SCE&G's 2017 Reserve Margin study make
5 this process even more difficult. For example, only through conversations with SCE&G
6 witnesses was I informed of the differences in the data SCE&G used to derive their
7 regression models of seasonal weather response. This data was not provided when ORS
8 requested SCE&G to provide all of the support calculations and documentation to
9 substantiate its calculations. Those differences substantially sidetracked and delayed our
10 analysis of the reasonableness of SCE&G's study. Other parties, not informed of the data
11 inconsistency, may have been similarly misdirected.

12 SCE&G's assertion that there are no avoided capacity costs for fifteen (15) years if
13 there are no winter capacity reductions, strikes me as a position that requires that the winter
14 capacity constraint be nearly indisputable. I do not believe that SCE&G has proven that
15 condition. They may be correct, but given the large shift in approach and shift in the way
16 one would think about capacity needs, I believe that SCE&G's position should not be
17 adopted in this Docket.

18 **Q. YOU MENTIONED THE DIFFICULTY IN EVALUATING SCE&G'S FILINGS,**
19 **BUT ARE THERE ANY SPECIFIC ISSUES THAT YOU COULD IDENTIFY?**

20 **A.** Yes, I believe that SCE&G is overestimating the amount of excess capacity the
21 utility needs in the winter season because of a flawed 2017 Reserve Margin Study
22 ("Study"). I also believe the Company is forecasting summer and winter peak demands

for future years in an inconsistent manner that creates a potentially false indication of higher capacity need for the winter season.

Q. HOW IS SCE&G'S 2017 RESERVE MARGIN STUDY FLAWED?

A. The study (Exhibit JML-2) starts with a very simplistic method of simply adding together estimated peak variation from weather and variation in supply capacity to arrive at "Total Reserve MWs". This is done separately for the summer and winter season and divided by the summer and winter peak loads to arrive at the Reserve Margin Percentage (Exhibit JML-2, p. 8). These calculations are shown in Table 4 of the study, reproduced below.

Table 1: Reproduction of Table-4, Exhibit JML-2, p. 8

Reserve Margin for Summer and Winter Peak Periods		
	Summer	Winter
VACAR Operating	200	200
Demand-Side Risk	208	542
Supply-Side Risk	230	224
Total Reserve MWs	638	966
Normal Peak Demand	4744	4630
Reserve Margin %	13.4%	20.9%
Reserve Margin Policy	14%	21%

To my knowledge, this is not an industry standard approach (in contrast to the industry standard approaches such as the Loss of Load Probability method presented by SCE&G in its prior 2012 Reserve Margin Study).

Setting aside, however, the appropriateness of the method, the implementation of the method is flawed because SCE&G's determination of the winter season peak demand variation is overstated. By overstating the winter variability, SCE&G would be overstating the need for reserve margin in the winter. Indeed, in looking at Table-4 reproduced above,

one sees that the variation in peak demand (called the “Demand-Side Risk” in the table) accounts for the entirety of the increase in the winter reserve margin over the summer reserve margin.

To emphasize this point, the table below shows the exact same reserve margin calculations, but replaces SCE&G’s estimate of winter demand-side risk with an estimate I produced using SCE&G’s data (once I was informed of the data inconsistency problem with their provided data). The table shows that with E3’s demand-risk, the amount of extra capacity required in the winter compared to summer is only 211 MW (849 MW – 638 MW) --- not 328 MW as SCE&G claims.

Table 2: Reserve Margin with Alternate Winter Peak Variation

Reserve Margin for Summer and Winter Peak Periods			Difference
	Summer	Winter	
VACAR Operating	200	200	211
Demand-Side Risk	208	425	
Supply-Side Risk	230	224	
Total Reserve MWs	638	849	
Normal Peak Demand	4744	4630	4.9%
Reserve Margin %	13.4%	18.3%	

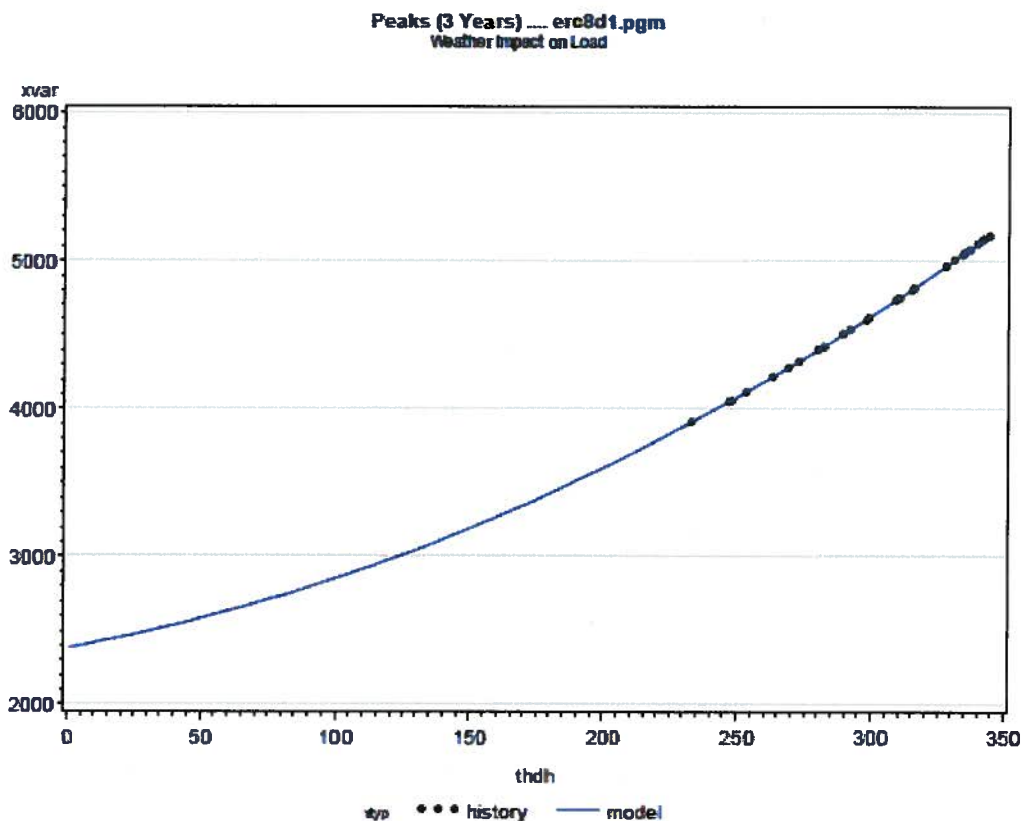
With this change, the winter reserve margin drops 2%, and the gap between the winter and summer reserve margins drops from 7% (21% - 14%) to about 5%.

Q. WHY DO YOU BELIEVE THAT SCE&G HAS OVERSTATED THE WINTER VARIABILITY?

A. SCE&G uses regression equations to estimate what peak demand would be on SCE&G’s system today given the weather that occurred on historical peak days since 1991. The lower figure on Exhibit JML-2, page 4, shows the estimated peak demands from the winter regression equation, with the points corresponding to the historical peak day

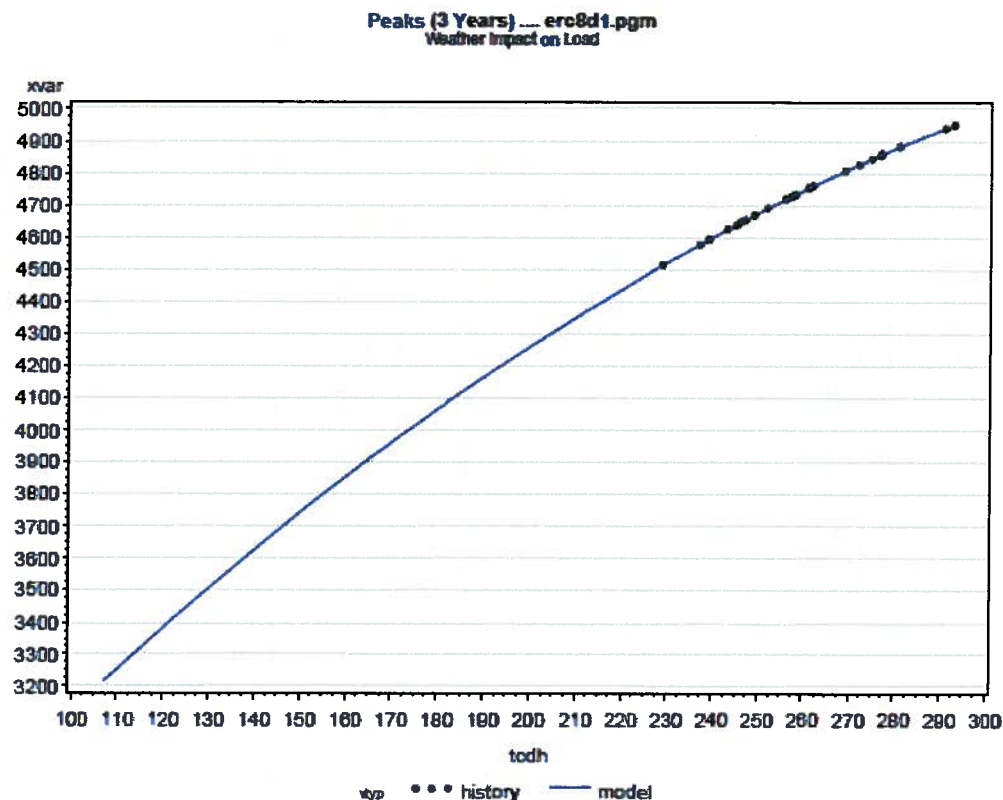
temperatures and corresponding simulated peak loads indicated by the black dots. The figure is reproduced below. The x-axis is cooling degree hours. They represent the sum of the differences between a design temperature, say 60 degrees, and the actual temperature in each hour of the day. The colder the day, the higher the cooling degree hours.

Figure 1: SCE&G Estimate of Winter Peak Demand using Historical Weather (Exhibit JML-2, p. 4)



Note the shape of the regression line. It slopes upward at an increasing rate, so that it predicts that peak load will rise at an ever increasing rate as the days get colder. Contrast that to the shape of SCE&G's predicted peak loads in the summer. In the summer figure, reproduced below, the rate of increase declines as weather becomes more extreme. This is indicated by the slight downward curve of the regression results.

Figure 2: SCE&G Estimate of Summer Peak Demand using Historical Weather (Exhibit JML-2, p. 4)



The summer shape is what I would expect. As weather becomes more extreme, the cooling equipment becomes more heavily used, but eventually top out and cannot increase electricity usage any further. As individual units top out, one sees diminishing increases in load as temperatures worsen.

In contrast, the winter shape has an upward curve, which is counter to engineering-based expectations. This upward curve also exacerbates the variation in peak demand, compared to the downward curve of the summer predictions. This can result in an overly large estimate of winter variability for the winter season compared to the summer season.

Q. WHAT IS YOUR ESTIMATE OF SCE&G WINTER VARIABILITY?

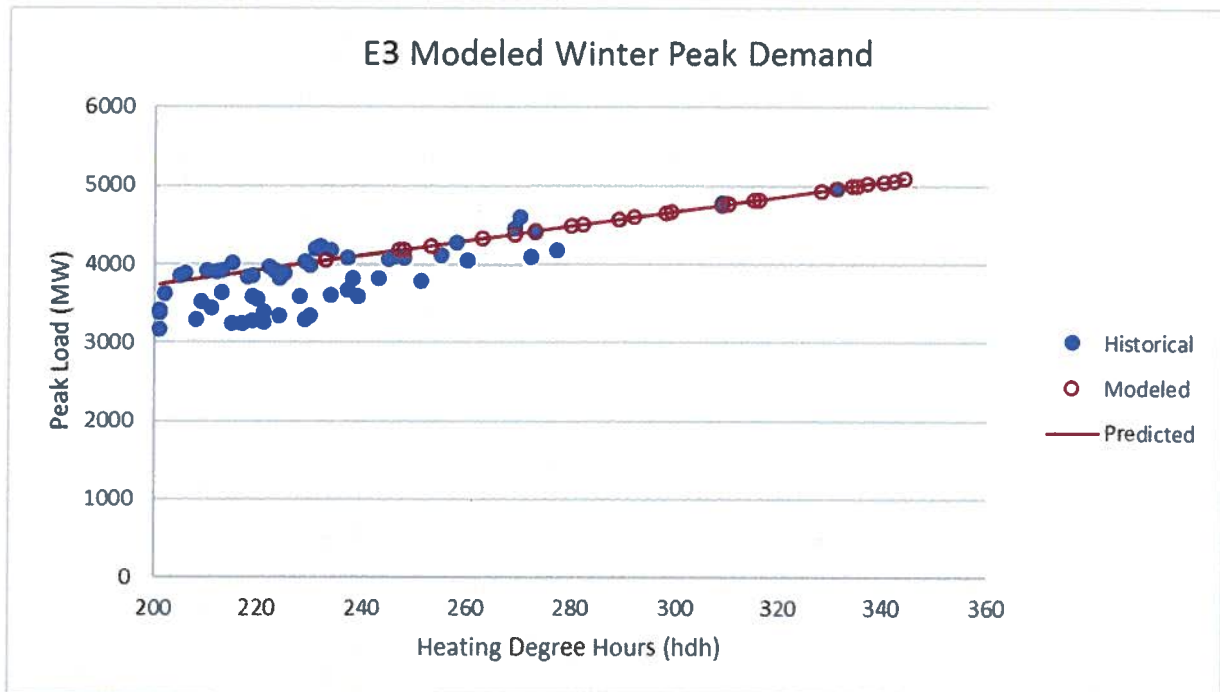
1 **A.** I estimate that SCE&G winter variability is 425 MW, as compared to SCE&G's
2 estimate of 542 MW. I estimated the variability using a corrected version of SCE&G's
3 regression data set. The most significant correction I made was to remove days that had
4 relative low temperatures. In the 27 years of historical winter peak data that SCE&G
5 provided, the lowest heating degree hour ("hdh") was 233. Hdh are the sum of the
6 difference between a day's hourly temperatures and a base temperature such as 60 degrees.
7 The colder the day, the larger the hdh. I, therefore, excluded all days with hdh at or below
8 200 from the dataset, as such moderate days would have little chance of being a peak winter
9 day. By doing this, the remaining data produced a regression model that gave a better
10 representation of peak electricity demand on winter peak days, and also revealed a more
11 logical linear relationship with hdh, rather than the quadratic relationship that SCE&G
12 obtained with the overly large dataset.

13 Put another way, SCE&G created a model to estimate daily peak load for any day
14 in the winter. The response of customers to changes in hdh at moderate levels is likely not
15 the same as their response at higher hdh levels. This is probably why the SCE&G model
16 has the curved shape. It is trying to fit two different response shapes. By reducing the data
17 set to exclude those moderate hdh days, my model specification is not affected by the
18 moderate days, and the curved shape is rejected for my data set --- which shows that the
19 curved response shape is not fundamental to customer response at high hdh levels.

20 The figure below shows the historical data that I used in my analysis, as well as the
21 predicted peak loads based on hdh. The round circles are the predicted peak loads for 2016,
22 at the peak day hdh observed over the last 27 years. The predicted peak would vary by

month, so I have assumed January peaks for the figure. Note that the January assumption does not affect the calculation of winter demand-side risk.

Figure 3: E3 Modeled Winter Peak Demand using Historical Weather



SCE&G defined demand-side risk as the difference between the modeled maximum peak demand and average peak demand using the 27 years of peak hdh. The table below compares SCE&G's values used in their 2017 Reserve Margin study, and the results from my regression model. The lower deviation of 425 MW is the value used in my Reserve Margin calculation earlier in this testimony.

Table 3: Winter Demand Side Risk

MW Peak Demand - Winter				
	Maximum	Normal	Deviation	%Deviation
SCE&G JML-2, Table 1	5172	4630	542	11.7%
E3	5087	4662	425	9.1%

Table 4: E3 Regression Model Specifications

SUMMARY OUTPUT								
Regression Statistics								
Multiple R	0.960166241							
R Square	0.921919211							
Adjusted R Square	0.891950135							
Standard Error	118.9069773							
Observations	56							
ANOVA								
	df	SS	MS	F	Significance F			
Regression	7	8180115.389	1168587.913	96.42585561	4.61588E-26			
Residual	49	692804.5932	14138.86925					
Total	56	8872919.982						
	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	1747.325757	153.9953487	11.34661386	2.57753E-15	1437.860518	2056.790996	1437.860518	2056.790996
ihol	-647.1513228	123.0564432	-5.258979586	3.1645E-06	-894.4425039	-399.8601417	-894.4425039	-399.8601417
wkend	-436.1093908	35.3924265	-12.32211052	1.26743E-16	-507.2331347	-364.9856469	-507.2331347	-364.9856469
hdh	9.390656604	0.640992562	14.65018031	#NUM!	8.102533825	10.67877938	8.102533825	10.67877938
Jan	109.0530828	47.81469373	2.280744146	0.026949729	12.96585833	205.1403073	12.96585833	205.1403073
Feb	154.3791379	49.20292825	3.137600614	0.002881245	55.50215169	253.2561241	55.50215169	253.2561241
Nov	-141.8875	64.24746114	-2.208453027	0.031921619	-270.997607	-12.77739305	-270.997607	-12.77739305

Q. IF YOUR LOWER WINTER RESERVE MARGIN VALUES WERE USED IN SCE&G'S IRP PROCESS, WOULD SUMMER CAPACITY NEEDS SURPASS WINTER CAPACITY NEEDS IN SOME YEARS AND THEREBY RESULT IN AVOIDED CAPACITY VALUE FOR SUMMER-FOCUSED RESOURCES LIKE SOLAR?

A. Yes, but additional corrections should be applied to the load and resource balance table to properly reflect the difference in summer and winter capacity needs. The current table would suggest that six (6) in fifteen (15) years would benefit from summer capacity. That is to say, in six (6) of the fifteen (15) years the winter reserve percentage (line 15 in Exhibit JML-1) is more than 5% greater than the summer reserve percentage (I do not count years with baseload additions or seasonal capacity purchases). The 5% "rule" is based on the winter reserve margin requirement being 4.9% higher than the summer reserve margin

requirement. For example, if the winter reserve margin percentage in 2025 were 20%, and the summer percentage was 18%, there is only a 2% difference, and winter capacity needs would be binding over summer needs. Put another way, my winter reserve margin threshold is 18.4% and my summer reserve margin threshold is 13.4%. At 20% in the winter, there is 1.6% capacity above the threshold (20% - 18.4%). At 18% in the summer, there is 4.6% capacity above the threshold (18% - 13.4%). Since 1.6% is smaller than 4.6%, winter is the constrained season.

Table 5: Seasonal Reserve Margin Difference from Exhibit JML-1

	Winter reserves in excess of summer reserves	Note
2018	6.0%	Baseload and Firm Purchase
2019	1.4%	Firm Purchase
2020	0.6%	Firm Purchase
2021	3.1% 2.1%	Firm Purchase
2022	4.5%	Firm Purchase
2023	12.9%	Baseload added
2024	3.9%	
2025	4.3%	
2026	4.7%	
2027	5.0%	
2028	5.2%	
2029	5.4%	
2030	5.4%	
2031	7.2%	
2032	5.6%	

Q. WHAT CHANGES ARE NEEDED FOR THE LOAD AND RESOURCE TABLE, AND HOW WOULD THAT AFFECT THE VALUE OF SUMMER CAPACITY?

A. In order to properly value summer and winter capacity, it is important to remove any unintended bias between summer and winter values. Recall that SCE&G's method of

deriving the reserve margin threshold is to add up the extra capacity requirements from three components: 1) VACAR operating reserves, 2) demand-side risk, and 3) supply-side risk. The demand-side risk is the difference between the average annual peak and the maximum annual peak based on 27 recent years of data. It is therefore logical that the reserve margin threshold would be applied to forecasts of average annual peaks, since the risk of higher peaks is already embedded in the reserve margin threshold percentage.

The problem is that the load forecasts in the load and resource table (Exhibit JML-1) appear to be higher than any reasonable expectation of average peak, and moreover deviate more in the winter than the summer, which would be introducing a bias toward making winter the constrained capacity season. Table 6 shows that the gross territorial peak values in 2018 in the SCE&G load and resource table are higher than what normal loads should be given typical 1% per year growth rates since 2016. More importantly, the difference in MW is greater for winter than summer, which makes the winter appear relatively more capacity constrained than the summer.

Table 6: Potential Bias of Seasonal Peak Demands in SCE&G 2018 IRP (MW)

		Summer	Winter	Difference
1	Gross Territorial Peak from JML-1 for 2018	5077	5024	
2	Normal 2016 Peak from JML-2, table 1	4744	4630	
3	Assumed growth from 2016 to 2018	2%	2%	
4	Normal 2018 consistent with JML-2, table 1	4839	4723	
5	Difference (L1 - L4)	238	301	63

While the 63 MW bias appears small, if we apply these corrections to the SCE&G load and resource table by subtracting the seasonal differences shown in line 5 of Table 6 then summer becomes the constraining season in nine (9) of the fifteen (15) forecast years. That is a 50% increase from the six (6) out of fifteen (15) years when SCE&G's

uncorrected load and resource table is used. This is shown in Table 7, which excludes winter short term purchases and the 2023 addition of 540 MW of baseload capacity.

Table 7: Seasonal Reserve Margin Difference with Correction to Average Peak

	Winter reserves in excess of summer reserves	Note
2018	8.1%	Baseload added
2019	2.1%	
2020	1.9%	
2021	2.9% 1.9%	
2022	3.4%	
2023	4.6%	
2024	5.5%	
2025	5.8%	
2026	6.2%	
2027	6.5%	
2028	6.6%	
2029	6.8%	
2030	6.8%	
2031	8.6%	
2032	7.0%	

Q. DO YOU BELIEVE THAT YOUR CHANGES ABOVE PROVIDE AN ACCURATE REPRESENTATION OF THE VALUE OF SOLAR CAPACITY?

A. While I believe that my changes provide a better indication of the value of solar capacity, I suspect that there are other changes that should also be applied. While the corrections that I present are relatively small individually, their impact on the relationship between winter and summer capacity need highlights the sensitive nature of this problem. Essentially a new dimension has been added into the evaluation of peak capacity and avoided capacity costs. Because of the effect of solar on summer versus winter peaks, the

1 difference in summer versus winter capacity needs becomes critical to evaluate solar, and
2 I believe it has not received sufficient exploration in this Docket.

3 **Q. IN YOUR OPINION, ARE SCE&G'S AVOIDED CAPACITY COSTS**
4 **APPROPRIATE?**

5 **A.** No. SCE&G bases its assertion of zero avoided capacity cost for solar projects on
6 SCE&G being constrained by winter capacity needs, and unaided by summer capacity
7 reductions. This is a substantial change from the methodology and inputs used by SCE&G
8 to calculate prior PR-1 and PR-2 rates, and relies upon assumptions and studies conducted
9 in the 2018 IRP that have not been fully reviewed, vetted and/or approved by the
10 Commission. Given the large change in SCE&G's position, and the uncertainty over the
11 accuracy of its new position, I recommend that SCE&G's position of zero avoided capacity
12 costs be rejected at this time.

13 **Q. GIVEN THE PROBLEMS WITH SCE&G'S ANALYSIS, WHAT DO YOU**
14 **RECOMMEND THE COMMISSION ADOPT FOR PR-2 CAPACITY VALUE?**

15 **A.** I recommend that the PR-2 capacity value be set at 19.5% of the avoided cost of
16 per kW from a 100 MW change to SCE&G's base resource plan that excludes any non-
17 committed future resources and reflects any planned plant retirements of firm capacity.
18 Including 19.5% of the avoided capacity value is based on SCE&G's solar analysis that
19 found that a 100 MW increment of new solar would reduce summer peak demand by about
20 19.5 MW (Exhibit JML-4, p. 6). For example, in Docket No. 2016-2-E, SCE&G estimated
21 the long run avoided capacity cost for a 100 MW change to be \$21.34/kW-yr (Lynch direct
22 testimony, p. 15). Applying the 19.5% factor would have resulted in an avoided capacity
23 cost for solar of \$4.16/kW-yr.

1 Unfortunately, SCE&G has not provided a long-run avoided capacity cost in this
2 Docket. ORS attempted to acquire a capacity cost estimate from SCE&G, but SCE&G
3 declined.

4 Because of the time constraints and the lack of an avoided capacity cost calculation
5 by SCE&G in this Docket, I was unable to produce an independent estimate of avoided
6 capacity costs for a 100 MW change in supply. I recommend that SCE&G be required to
7 provide an estimate of long-run avoided capacity cost and the calculation for the long-run
8 avoided capacity costs. In addition, ORS and other parties should be allowed to review
9 and provide comment to the Commission based on SCE&G's estimate and calculation.
10 Alternatively, I recommend that the current capacity value be maintained for both PR-1
11 and PR-2 until a better capacity value can be provided in the next rate update.

12 **Q. DO YOU HAVE AN OPINION ON SCE&G'S POSITION OF NOT PROVIDING A**
13 **STANDARD RATE OFFER FOR NON-SOLAR RESOURCES?**

14 A. Yes. Despite the lack of ~~update~~uptake of the PR-2 rate by non-solar resources, I
15 believe that SCE&G should continue to provide a standard published rate for such
16 resources. The lack of a published rate would increase the uncertainty and engagement
17 costs for new resources. The need to commence a negotiation on compensation terms
18 would increase project lead times and costs for the developers, which could be a significant
19 barrier for such small projects.

20 **Q. PLEASE DESCRIBE CHANGES TO SCE&G'S FILED TOTAL VALUE OF NEM**
21 **DISTRIBUTED ENERGY RESOURCES.**

22 A. As required by Commission Order No. 2015-194, SCE&G must calculate 11
23 components of value for NEM Distributed Energy Resources ("DERs"). In Docket No.

2017-2-E, SCE&G calculated these 11 components of value; in Order No. 2017-246, the Commission determined the values SCE&G calculated complied with the NEM Methodology as approved by the Commission in Order No. 2015-194. On page 27 of witness Lynch's direct testimony, SCE&G reports the updated values for these same 11 components. Table 8 below summarizes the values as approved in Order No. 2017-246 and as filed in the current Docket. The significant changes are in the Avoided Energy Costs and Avoided Capacity Costs line items.

Table 8. Value of NEM Distributed Energy Resources (\$/kWh): 2017 Approved and 2018 Filed (Lynch pp. 26,27)

	Order No. 2017-246: IRP Planning Horizon (15-yr Levelized)	Docket No. 2018-2-E IRP Planning Horizon (15-yr Levelized)	Components
1	\$.03199	\$.03014	Avoided Energy Costs
2	\$.00172	\$0	Avoided Capacity Costs
3	\$0	\$0	Ancillary Services
4	\$0	\$0	T&D Capacity
5	\$.00004	\$.00004	Avoided Criteria Pollutants
6	\$0	\$0	Avoided CO ₂ Emission Cost
7	\$0	\$0	Fuel Hedge
8	\$0	\$0	Utility Integration & Interconnection Costs
9	\$0	\$0	Utility Administration Costs
10	\$0	\$0	Environmental Costs
11	\$.03375	\$.03018	Subtotal
12	\$.00276	\$.00246	Line Losses @ 0.9245
13	\$.03651	\$.03264	Total Value of NEM Distributed Energy Resources

Q. WHAT CAUSED THE DIFFERENCES IN AVOIDED ENERGY AND AVOIDED CAPACITY COSTS FOR NEM DISTRIBUTED ENERGY RESOURCES?

A. As described in witness Lynch's Direct Testimony, SCE&G bases its NEM DERs avoided energy and avoided capacity costs on the PURPA avoided cost values. The avoided energy costs are adjusted to remove criteria pollutants, which are accounted for separately in the "Avoided Criteria Pollutants" line item. The PURPA avoided energy cost decreased from last year, leading to a reduction in the NEM DERs avoided energy cost. Similarly, this year SCE&G claimed zero value for PURPA avoided capacity cost, which led to a zero value for the corresponding NEM DERs avoided capacity cost.

Q. ARE SCE&G's REASONS FOR WHY IT HAS ZERO VALUE FOR 7 OF THE OTHER COMPONENTS OF THE NEM DISTRIBUTED ENERGY RESOURCES TOTAL VALUE STACK REASONABLE?

A. Yes. SCE&G is following the methodology approved by the Commission in Order No. 2015-194 in evaluating the value of each component of the NEM DERs Total Value stack. Regarding T&D Capacity, it should be noted that some jurisdictions recognize the value NEM resources can provide in deferring T&D investments and therefore attribute capacity value to resources like solar. SCE&G's practice of designing transmission and distribution circuits to assume DER is not generating due to weather factors or because DER resources are off line does follow the Commission approved methodology, but it is a conservative approach. Regarding avoided CO₂ emissions, while some jurisdictions recognize value in avoided CO₂ Emissions, Commission Order No. 2015-194 directs SCE&G to use zero monetary value for CO₂ "until state or federal laws or regulations result

in an avoidable cost on Utility systems for these emissions.” (PSC Order No. 2015-194, p. 9)

Q. IN YOUR OPINION, ARE SCE&G’s VALUE OF NEM DISTRIBUTED ENERGY RESOURCES COSTS APPROPRIATE?

A. Excepting the Avoided Capacity Cost component, the filed SCE&G Value of NEM Distributed Energy Resources components are conservative, but appropriate. The Avoided Capacity Cost component is based on the PURPA Avoided Capacity Cost values, and I have previously discussed why I find the filed PURPA Avoided Capacity Cost values inappropriate. Should the Commission reject the Company’s proposed Avoided Capacity Cost values, the Total Value of NEM Distributed Energy Resources would be impacted.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.